FEASIBILITY OF REDUCING COSTS OF LIQUID FUELS AND ELECTRICITY FROM DEDICATED BIOMASS FEEDSTOCKS AND WASTE-TO-RESOURCE MANAGEMENT IN CALIFORNIA

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EXECUTIVE SUMMARY

Project Description, Objectives, and Benefits

Wood Industries Company (WICO) of Visalia, California performed this feasibility study with cost-shared funding from the U.S. Department of Energy's National Renewable Energy Laboratory (NREL). The objective of this project, as defined in the Statement of Work, is to develop a plan for integrating biomass production and conversion technologies for liquid fuels and electricity production. Specifically, the project was undertaken to determine potential sites for a biomass-to-ethanol plant in California and to perform an economic analysis based on plant size and process options.

Existing technologies for supplying cellulosic biomass and converting it to ethanol are too expensive to allow such projects to compete for market share in the motor fuel market. Cost reduction strategies inherent in the WICO project include:

1. Select sites to optimize production, transportation, and marketing.
2. Direct the harvested products of biomass crops to their highest end uses.
3. Develop markets for high-value (non-fuel) biomass products, using dedicated feedstock supply systems (DFSS) involving crops such as kenaf, sorghum, and eucalyptus.
4. Use biomass residues (that would otherwise require costly disposal) as fuel conversion feedstocks.
5. Integrate waste-to-resource management into the DFSS; i.e., use of set-aside and damaged farmland, use of municipal and agricultural processing wastewater for irrigation, use of compost from municipal, agricultural, and other waste products (manure and biomass ash) for fertilizer.

WICO's long-term objective is to build an integrated farm-based ethanol/cogeneration business, and to demonstrate the principles of waste-to-resource management that lead to economic and environmental benefits for agricultural communities such as Visalia. The basic concept will be to promote biodiversity and sustainability through the integration of the various project components.

The resource recycling features of the project that will demonstrate the sustainability of the concept are as follows:

- Growing of energy crops such as kenaf, switchgrass, sorghum, and hybrid poplar.
- On-site ethanol production facilities utilizing these crops as biofuels.
- Cogeneration of electricity and steam from ethanol fuel byproducts.
- On-site composting of the residual char with other feedstocks such as wood, urban green waste, and agricultural crop residues.
- On-site use of compost for soil enhancement and demonstration trials of various energy crops.
- Habitat restoration using various mulches, compost, and soil products produced on-site.

The project statement of work called for determining the economic potential achieved by coupling liquid fuels (ethanol) and co-product production facilities with existing or new biomass-fueled power plants. Once demonstrated through scaleup, this strategy could offer a viable solution to survival and stability of California's diminishing biomass-fueled electric energy industry.

The best integration opportunity is to couple ethanol production with a recently curtailed or a still-operating biomass plant, allowing a chance for survival and future prosperity in California's restructuring electric utility industry. The integration of facilities to process biomass crop residues and produce liquid fuels, co-products, steam, and electricity at the same location offers:

- High economic efficiency
- Production of co-products
- Low-cost steam and power
- Good feedstock selection and volume
- High conversion and recovery efficiency
- Technology and system flexibility
- Highly trained and specialized personnel pool
- Environmental benefits
- Emission offset credits

Proposed Site, Feedstock Types and Availability, and Environmental Issues

The highly productive farmland in the Central Valley of California produces large quantities of residues that could serve as excellent biomass feedstocks for conversion to ethanol and byproduct steam and electricity. In addition, there are many thousands of acres of marginal farmland in the region that could be used to grow dedicated energy crops. WICO is located in the heart of this region, in Visalia (Tulare County).

Tulare County has about 775,000 acres of irrigated farmlands and is the largest milk producing area in the world. The principal field crops are cotton, alfalfa, silage, and wheat (a total of 408,000 acres). The principal orchard crops are citrus, walnuts, plums, almonds, and peaches (a total of 167,000 acres). In addition, Tulare County has 68,000 acres of vineyards. Sixty percent of all jobs in Tulare County are related to agriculture. Table S-1 shows Pacific Gas & Electric Company's (PG&E's) estimated availability of biomass fuels in California's four largest agricultural counties (Tulare County plus three adjacent counties).

Table S-1
PG&E Estimates of Biomass Fuel Availability by County
(Thousands of Dry Tons)

	Fresno	Tulare	Kern	Kings
Orchards	81	124	101	15
Vineyards	81	27	30	1
Field crops	158	94	132	114
Mill wastes	49	31	11	0
Forest residues	14	9	3	0
Landfill wood	21	16	47	3
Total	404	299	324	134

(SOURCE: PG&E 1991)

Table S-2 presents WICO's estimates of some of the highest-volume agricultural and other residues available within a 25-mile radius of Visalia (based on various publications and on discussions with farmers). Not counting the manure and the MSW, over 175,000 tons/year (t/y) of biomass residues are presently available as feedstock, and in fact represent disposal problems to the farmers that produce them. At an assumed conversion yield ranging from 70 to 120 gallons of ethanol per ton, this is enough feedstock to produce 12 to 21 million gallons/year of ethanol.

Tulare County is situated 180 miles north of Los Angeles and 200 miles south of San Francisco. Extensive transportation networks, including rail and connections to Interstate 5 and State Highway 99, provide good access to markets. Land and labor costs are low. Because of these features, Tulare County is considered one of the most cost-efficient areas in which to do business and its manufacturing and industrial sectors are growing steadily.

Table S-2
Residues Available Within a 25-Mile Radius of Visalia

Material	Amount (t/y)	~Cost ($/t)*	Season
Cotton gin trash**	50,000	0	Dec.-Jan.
Walnut hulls	32,000	0	Sept.-Nov.
Green waste and paper	45,000		All year
Manure (dairy, poultry)	1,500,000	2.50	All year
Hardwood chips	50,000		
MSW		-16-20	All year

*FOB at site of generation; transportation will add about $4.00/dt.
**Cotton stalks could make an additional 200,000 tons/year of biomass available from the 100,000 acres of cotton crop within a 25-mile radius of Visalia. [Coates 1995]

Tulare County is home to some of the nation's largest food processing companies: Kraft General Foods, Eagle Snacks, Stella Cheese, Haagen Dazs Ice Cream, California Milk Producers and many more. Tulare County is responsible for the direct production of over 250 commodities.

Building upon a solid agricultural base, Tulare County has sought to diversify its economy with competitive incentives. The results have been very successful with the county seeing major expansions in food processing and manufacturing. The economy of the southern San Joaquin Valley is primarily based on agriculture and related industry, creating a large customer base for producers of fertilizer, compost, and other soil amendments. A rapidly expanding population ensures an increasing supply of feedstocks, including compostable materials such as green yard waste, food waste, and municipal sludge.

Cotton commands the most acreage at this time. Second is alfalfa which is greatly valued for its cash flow as it is harvested seven to nine times per year, and has 75,000 to over 100,000 acres planted. Corn follows; 85% of the crop was for silage on dairies. (Corn affords the grower great flexibility in marketing and crop rotation as it offers a selection of short to long season varieties.) Similar to corn, utilization of the "small grains" has shifted to an increasing role as dairy feed. Many varieties of beans are grown including blackeyes, garbanzos and soybeans. Sugarbeets are grown but are no longer processed in the county.

Dairying in Tulare County has come a long way since its inception in 1860 when the first creamery was built. By the turn of the century there were 7,000 cows in the county. In 1993 California surpassed Wisconsin as the number one dairy state, and in 1994, Tulare County became the leading dairy county in the nation.

The information and analyses presented in this feasibility study report are generally from the perspective of an initial commercial project implemented at WICO's demofarm in Visalia. The initial commercial project could also be implemented at the site of an existing biomass power plant. The capital cost of the project would probably be reduced somewhat by locating it at an existing site, and there might be advantages in permitting requirements. WICO's demofarm site also offers specific advantages, such as co-location with a wastewater treatment plant, with rail and pipeline rights-of-way, and with farms capable of producing dedicated feedstocks. Also, the status of the ethanol production technology is such that small-scale proof-of-concept (i.e., PDU operation) is necessary in order to demonstrate to the power plant owners and operators that such an investment in modifying their facilities would be sound. Primarily for this reason, WICO decided during this feasibility study to evaluate construction and operation of an integrated PDU at the Visalia demofarm site, and to evaluate an initial commercial project located at the same site.

Looking at the opportunity from the perspective of one of the existing power plant owners, it is interesting to examine the situation today compared to one or two years ago. In 1994, the power plant was operating and selling electricity to the utility at a price of (typically) 9-11¢/kWh, burning biomass that cost $40-50/dry ton. Since then, the plant may have negotiated a curtailment agreement with the utility. It may be shut down. It may be in a position to reopen, with its capital costs (loans) paid off under the curtailment agreement, with biomass fuel (in a distressed market due to numerous plant shutdowns) now available at about $15/dry ton. Hypothetically, the plant's cost structure, with all costs converted to ¢/kWh of electricity produced assuming an 80% annual capacity factor and a net heat rate of 17,000 Btu/kWh, might be as follows:

	1994	**1995**
Carrying charges, ¢/kWh	4.5	0.0
Fuel costs, ¢/kWh	4.5	1.5
O&M costs, ¢/kWh	1.6	1.6
Total cost of electricity, ¢/kWh	10.6	3.1

As these hypothetical figures illustrate, the past year has seen major changes taking place in California's existing biomass energy industry. The situation today can best be described as unstable and politically sensitive, with the future full of uncertainties. The partial or total curtailment of at least fourteen biomass energy facilities (the core of which are located within a 50-mile radius of the project site) has directed around one million tons/year of biomass back to landfilling or open burning and severely damaged a sophisticated processing, collection, and transportation infrastructure.

With respect to cost structure, some of the power plants may be in a position similar to that illustrated above, able to produce electricity at a fraction of the cost of a year ago. This does not necessarily mean that these plants will be able to compete successfully in the emerging competitive electricity industry. However, with their capital costs "written off", with the cost of fuel slashed by major reductions in the regional demand for fuel, and with the added value of steam- and power-purchasing, fuel-providing partners (i.e., ethanol plants) onsite, these existing power plants have at least a better chance of competing (with natural gas combined cycle plants) than they would have had if the 1994 status quo had continued.

While this situation presents opportunities for the economic use of biomass to produce steam and electricity, it should be recognized that it is not a sustainable or repeatable situation. New plants cannot have their costs written off instantaneously. A price of $15/dry ton for processed, delivered, high-quality fuel is below the actual cost of providing that fuel in most cases -- unless the residue generators (e.g., farmers, orchard growers, urban wood waste collectors) provide a significant tipping fee. This they have been unwilling to do, and they will continue to be unwilling unless regulations are promulgated that strictly prohibit alternate disposal techniques such as open burning and landfilling.

In co-locating with an ethanol plant, a power producer can significantly enhance its competitive position by obtaining access to lower-cost fuel as well as access to a major customer for steam and electricity. Depending on the transfer prices agreed to by the co-located facilities, the fuel cost for the ethanol plant byproducts (lignin and biogas) could be considered to be as low as zero. A secondary effect may also be important: for the most part, the ethanol plant feedstocks will be agricultural residues or crops that are not able to be used as boiler fuel because of their high alkali content or other properties. Thus, the development of an ethanol industry will increase the regional supply of high-quality biomass boiler fuel, which will tend to depress its price, while offering new solutions for an ever-growing volume of urban wood wastes.

Electricity sales to the co-located ethanol facility will effectively be valued by the parties at prices between the (low) wholesale price that the power producer would receive from the grid or power pool, and the (much higher) retail price that the ethanol plant would pay to purchase the power from the local utility or distribution company. In other words, the power producer will (in effect, regardless of the accounting transactions) receive a premium price for the electricity it sells to its partner, the ethanol plant. The steam sales from the power producer to the ethanol plant will also provide an economic benefit to the joint enterprise. The power producer might not otherwise be able to market this steam (in essence, Btus that would be wasted), and the ethanol plant would have to build its own boiler or otherwise purchase the steam.

Implementation of the proposed project would raise no significant environmental issues; in fact, the production of renewable fuel from sustainable agricultural operations has many environmental benefits compared to existing fossil fuel production and use. An environmental permitting and monitoring plan has been developed, and shows no roadblocks to timely implementation of the project. Permitting requirements that need to be addressed are:

- Special Use Permit (Amendment or new permit)
- Tulare County Airport Land Use Commission
- CEQA - Environmental Impact Report
- NEPA - Environmental Evaluation Request Form
- Authority to Construct (San Joaquin Valley Unified Air Quality Management District)
- Industrial Discharge Permit option
- Waste Discharge Requirements option
- NOI - NPDES General Industrial Solid Waste Permit
- Pre-Manufacturing Notification and Registration

The market for ethanol in California is far larger than existing local producers can supply. Of the 50 or 60 million gallons of ethanol per year currently being sold to refiners in California, about 5 million gallons are produced in California. The remainder is transported from other states, primarily in the midwest. Thus, the 5 million gallon/year plant evaluated by WICO for the initial commercial phase of its project would have a ready market. The project site location, close to the geographic center of California, will achieve higher marketing and transport efficiencies for both feedstock receipts and product distribution.

Parallel Products is an ethanol producer and the leading marketer of ethanol in California. It has agreed to assist in the financing, design, and operation of the ethanol plant, and to market all of the ethanol produced by the plant.

Process Description, Design Basis, Plant Size, and Cost

The initial commercial plant will produce about 5 to 6 million gallons of ethanol per year from farm-grown biomass, plus about 3 MW of electricity (2 MW of which is used internally) from the byproducts of the ethanol process. The primary byproducts are lignin (a component of biomass that does not convert to ethanol) and biogas (methane) from the anaerobic digestion of wastewater components.

The specific types of biomass used as feedstock will vary with the season of the year. Some of the highest-volume residues available within a 25-mile radius of Visalia include cotton gin trash, walnut hulls, green waste and paper, manure (both dairy and poultry), hardwood chips, and municipal solid waste. WICO has been successfully growing sweet sorghum, kenaf, and eucalyptus on its 100-acre demofarm. These are projected to be highly productive energy and industrial crops.

Briefly, the process steps include:

- Feedstock preparation and milling
- Prehydrolysis with dilute sulfuric acid and live steam, followed by neutralization with lime
- Production of cellulase enzyme in fermenters
- Fermentation of xylose
- Simultaneous saccharification and fermentation (SSF) of cellulose
- Recovery and purification of ethanol by distillation and molecular sieve separation
- Separation of residual solids from the distillation bottoms
- Wastewater treatment by anaerobic digestion and aerobic treatment
- Cogeneration of steam and electricity using byproducts from the ethanol plant as fuels

The steam and electricity produced in the cogeneration plant are used in the ethanol plant. The major electricity demand is in the feedstock milling area, and the major steam demand is in the distillation section. Any excess energy produced in the cogeneration plant will be sold to third parties as electricity and possibly as steam.

Table S-3 summarizes the plant heat and material balance information, including rough estimates of air emissions from the cogeneration plant. These emissions estimates are based on measured emissions from operating biomass-fired boilers in California. It is likely that the existing biomass power plant selected for use in this project will have a greater capacity than shown in Table S-3 (roughly 3 MW plus 25,000 lb/hr of steam). If so, additional biomass could be fed directly to this plant and additional electricity could be sold.

The base case (conservative) estimated capital cost for the ethanol/cogeneration plant of $18 million ($3.60/annual gallon) was derived from published literature. A goal (or optimistic) capital cost of $10 million was also considered in the economic analysis. Achieving this goal would primarily be a function of the ability of WICO and its collaborators to locate suitable used equipment.

Table S-3
Summary of Plant Heat and Material Balance Information

	Conservative Yields	High Yields
Ethanol (200 proof) production capacity, million gallons/year	5	6.22
Raw feedstock to ethanol plant, dry tons/day	180	180
Green tons/day (assuming 50% average moisture)	360	360
Cogeneration plant capacity:		
Total electricity, kW	3,184	2,585
Electricity to ethanol plant, kW	2,132	2,145
Electricity for sale, kW	1,051	440
150 psig steam to ethanol plant, lb/hr	3,881	3,881
50 psig steam to ethanol plant, lb/hr	20,353	24,612
Fuel from ethanol plant to cogeneration plant, dry tons/day	64	47
Methane from ethanol plant to cogeneration plant, lb/hr	387	256
Other biomass fuel to cogeneration plant, dry tons/day	0	0
Emissions, lb/hr:		
Flue gas		
Carbon monoxide	4	4
Sulfur oxides	4	4
Nitrogen oxides	4	4
Particulates	0.002	0.002
Bottom ash	6	6
Fly ash	23	23

Estimated operating costs for the ethanol/cogeneration plant are shown in Table S-4.

Table S-4
Estimated Operating Costs
($000/Year)

Headquarters office	50
Plant payroll	1,600
Professional services	50
Biomass feedstock ($10/dry ton)*	591
Consumables	750
Insurance	15
Property tax	77
Interest (8.5%)**	657
Book depreciation (30 year SL)	555
Total operating costs	4,345

*Biomass feedstock cost is a key variable. The value of $10/dry ton is an example.
**The amount of interest declines each year as the loan is paid off (see Table V-3).

Summary of Economics and Sensitivity Analysis

Preliminary economic analysis and sensitivity analysis shows that the ethanol/cogeneration project should be viable under most combinations of assumptions within a range of assumed conditions, including:

- Plant capital cost between $10 and $18 million, or $2.00 and $3.60 per annual gallon.
- Ethanol yield of 5 to 6.22 million gallons/year from 180 dry tons/day of biomass, or 85 to 105 gallons per dry ton.
- Ethanol price between $0.90 and $1.10/gallon, and electricity price of 3¢/kWh.
- Biomass feedstock cost between $0 and $20 per dry ton.
- Government cost share in the plant capital cost between zero and 50%.

Table S-5 summarizes the input data and key results of the economic analysis performed for a 5 million gallon/year ethanol/cogeneration plant. The ethanol yield is consistent with the conservative yield case shown above (84.6 gallons/dry ton of feedstock). Net electricity sales are slightly over 1 MW. The ethanol sales price is assumed to be $1.10/gallon, and the electricity sales price is assumed to be 3¢/kWh. The biomass feedstock cost is assumed to be $10/dry ton. Because the processing and transport cost for most biomass residues exceeds $10/dry ton, this assumption implies that WICO receives a tipping fee to take at least some of the material.

The plant capital cost totals $18 million. This cost is spread over the assumed design/construction period of more than two years, from late 1995 to the end of 1997. It is assumed that the government provides a 50% cost share. The plant is assumed to start up in 1998 and to achieve a 50% annual capacity factor during that year. In successive years, the plant's capacity factor is assumed to be 90%. Operating costs are as shown in Table S-4.

It is assumed that the project qualifies for an accelerated 5-year depreciation schedule, and that the financing of the private sector share of the plant investment is 20% equity and 80% debt. The loan interest rate is assumed to be 8.5%.

During the construction period, capital costs are assumed to escalate at a 2% rate per year. Over the life of the project, energy prices (i.e., the product ethanol and electricity) are assumed to escalate at a rate of 3% per year. The general inflation rate (which applies to all other costs in the analysis, e.g., operating costs) is assumed to be 4% per year.

The "Key Results Summary" at the bottom of Table S-5 shows that these assumptions result in a total equity invested by the private sector investors of $1,933,000, and a total amount of funds

Table S-5
Economic Analysis
(Dollars in Thousands)

Ethanol sales, million gal/yr	5	Ethanol price, $/gallon	1.10
Electricity sales, kW	1,051	Electricity price, $/kWh	0.030
Biomass feed rate, dt/day	180	Annual capacity factor:	
Feedstock cost, $/dt	10.00	Startup year (1998)	50%
		Years 1999-n	90%
Capital costs (1995 $):			
Land; site preparation	100	Insurance rate, % of	
Engineering and permitting	1,800	plant and equipment cost	0.10%
Plant and equipment	15,200		
Startup costs	900	Property tax rate, % of	
Total capital costs	18,000	land plus plant cost	0.50%
Government cost share, %	50%	Federal income tax rate	35.00%
		State income tax rate	10.00%
Book (straight line) depreciation period, years	30	Financing:	
		% equity	20.00%
Tax (accelerated) depreciation schedule:		% debt	80.00%
(5-year MACRS) Year: 1	20.00%	Loan interest rate, %	8.50%
2	32.00%		
3	19.20%	Capital cost escalation rate, %	2.00%
4	11.52%	Energy price escalator, %	3.00%
5	11.52%	Inflation rate, %	4.00%
6	5.76%	Discount rate for NPV calc, %	10.00%

Key Results Summary

Total equity invested	1,933		
Total funds borrowed	7,733	NPV at 10%	5,425
Government cost share	9,666		
		IRR	**39%**

borrowed of $7,733,000. This is matched by a government cost share of $9,666,000. The calculated internal rate of return (IRR) on the equity investment, based on the project cash flows over a 24-year period, is 39%. The net present value of the cash flows, discounted at a 10% discount rate, is $5,425,000.

These results indicate that the project may be economically viable. Many of the assumptions are believed to be conservative: e.g., the ethanol yield, the capital cost of the plant, the electricity price, and the energy price escalation rate. However, the assumptions that the government will share 50% of the capital cost of the plant, and that the biomass feedstock cost will be $10/dry ton, may be optimistic.

Table S-6 shows the results of a number of additional economic analysis cases similar to the one presented above. Sensitivity case 1 shows the base case results for reference: an equity investment of $1,933,000, and in the conservative yield case, an IRR of 39% and a net present value (NPV) of $5,425,000 at a 10% discount rate. The "high yield" base case (which produces 6.22 million gallons/year from the same amount of feedstock) results in an IRR of 61% and a NPV of $10,038,000. Thus, ethanol yield is a powerful variable affecting the economic viability of the project. With all other variables held constant, a 24.4% increase in ethanol yield caused a 56% increase in the project IRR and an 85% increase in the NPV.

Sensitivity case 2 shows that the project economics are also quite sensitive to feedstock cost. In the conservative yield case, reducing the feedstock cost from $10/dry ton (dt) to $0/dt raised the IRR to 55% (a 41% increase over the base case IRR) and raised the NPV to $8,966,000 (a 65% increase over the base case NPV). In the high yield case, the effect of feedstock cost is still very significant, but to a lesser extent than in the conservative yield case: the IRR increases by 21% and the NPV increases by 33%.

Sensitivity case 3 shows the government cost share reduced to zero and the feedstock cost also reduced to $0/dry ton. The equity investment doubles to $3,867,000. In the conservative yield case, the IRR is 21%, and the NPV is $3,286,000. In the high yield case, the IRR is 34% and the NPV is $7,841,000. This sensitivity case shows that the project is probably economically viable with no government cost share, if the feedstock cost is very low ($0/dt).

Sensitivity case 4 also shows the government cost share reduced to zero, but the feedstock cost is increased to $20/dt. This case results in negative IRR and NPV values for the conservative yield case, and marginal values of 13% IRR and $754,000 NPV for the high yield case. Not shown on the table is the intermediate case with feedstock cost equal to $10/dt (the base case with no government cost share). This case gives an IRR of 8% and a NPV of -$507,000 for conservative yields, and an IRR of 25% and a NPV of $4,416,000 for high yields. These cases imply that the project is marginally viable, or perhaps not viable, in a scenario with no government cost share and a feedstock cost in the range of $10 to $20/dt.

Sensitivity case 5 is the same as sensitivity case 3, except that 100% equity financing is assumed instead of 20% equity/80% debt. The equity investment is $19,333,000; in the conservative yield

Table S-6
Sensitivity Analysis

Case	Equity, $000	Conservative Yields: IRR, %	Conservative Yields: NPV at 10%, $000	High Yields: IRR, %	High Yields: NPV at 10%, $000
1. Base case*	1,933	39	5,425	61	10,038
2. Feedstock = $0/dt	1,933	55	8,966	74	13,350
3. DOE share = $0 Feedstock = $0/dt	3,867	21	3,286	34	7,841
4. DOE share = $0 Feedstock = $20/dt	3,867	<0	-5,204	13	754
5. DOE share = $0 Feedstock = $0/dt 100% equity	19,333	9	-596	13	3,662
6. DOE share = 50% Feedstock = $0/dt Capital cost = $10M	1,103	89	10,198	112	14,268
7. Ditto; Feedstock = $20/dt	1,103	44	3,631	77	8,009
8. Ditto; DOE share = $0	2,206	12	328	37	4,900
9. Ditto; Feedstock = $0/dt	2,206	46	7,129	62	11,242
10. Base case, plus: Ethanol = $1.00/gal	1,933	25	2,758	47	7,091
11. Base case, plus: Ethanol = $0.90/gal	1,933	6	-506	31	3,929

*Base case assumptions:	Conservative Yields	High Yields
Ethanol sales, million gal/yr	5	6.22
Ethanol price, $/gallon	1.10	1.10
Electricity sales, kW	1,051	440
Electricity price, $/kWh	0.03	0.03
Biomass feed rate, dt/day	180	180
Feedstock cost, $/dt	10.00	10.00
DOE cost share, %	50	50
% equity	20	20

case the IRR is 9% and the NPV is -$596,000; in the high yield case the IRR is 13% and the NPV is $3,662,000.

Sensitivity cases 6 through 9 explore the impact of reducing the plant capital cost from $18 million to $10 million, as discussed above. These cases use feedstock costs of $0 and $20/dt, and government cost shares of 0 and 50%. Together, these cases show that the project is highly attractive throughout nearly this entire range of variables. The lowest IRR/NPV values occur in sensitivity case 8, with the feedstock cost at $20/dt and the government cost share at 0%. In this case, for conservative yields the IRR is 12% and the NPV is $328,000 (marginally feasible); for high yields the IRR is 37% and the NPV is $4,900,000 (definitely feasible).

Sensitivity cases 10 and 11 show that reducing the price of ethanol from the base case value of $1.10/gallon has a significant negative impact on the project economics. Case 10 shows that reducing the ethanol price to $1.00/gallon reduces the IRR to 25% from 39%, and reduces the NPV to $2,758,000 from $5,425,000 for conservative yields. Case 11 shows that further reducing the ethanol price to $0.90/gallon reduces the IRR to 6%, and reduces the NPV to -$506,000 for conservative yields.

The sensitivity of project economics to plant size depends on the economies of scale of capital costs and fixed operating costs. Data indicate that the capital cost scale exponent for small ethanol plants (<40 million gallons/year) is about 0.72. [Katzen et. al. 1992] Using this scale exponent and starting from the base case estimate of $18 million for a 5 million gallons/year facility, the capital costs of plants ranging up to 20 million gallons/year are as shown in Table S-7.

Table S-7
Capital Cost vs. Plant Size

Plant Size, Million Gallons/Year	Capital Cost, $ Million	Capital Cost, $/Annual Gallon
5	18	3.60
10	29.6	2.96
15	39.6	2.64
20	48.8	2.44

The capital costs shown in Table S-7 were input to the cash flow model. In addition, the plant payroll (i.e., number of plant employees) was adjusted using the same 0.72 scale factor. Feedstock and consumables costs were assumed to directly proportional to plant size (i.e., plant efficiency and yields were held constant). Other operating costs (headquarters office costs, professional services, insurance, and property tax) were assumed to be the same regardless of plant size. The resulting sensitivity cases are shown in Table S-8.

Table S-8
Sensitivity to Plant Size

		Conservative Yields		High Yields	
Plant Size, Million Gallons/Year	Equity, $000	IRR, %	NPV at 10%, $000	IRR, %	NPV at 10%, $000
5	1,933	39	5,425	61	10,038
10	3,159	61	16,461	84	25,075
15	4,216	74	28,348	97	40,905
20	5,188	84	40,648	107	57,158

The table shows that the economies of scale significantly reduce costs and thus improve the profitability of the project, given fixed feedstock and product prices. However, considerations of risk, of the learning required to perfect the new technology and feedstocks, and of the ability to raise capital, persuade WICO and its partners of the wisdom of starting with a small plant of about 5 million gallons/year capacity.

Recommendations/Next Steps

During the course of this feasibility study two significant points became clearer:

1. Conversion technology and dedicated feedstock supply system (DFSS) development are the two highest priority areas for research and development to achieve the lowest price per gallon of ethanol. However, feedstock sourcing, supply and processing, and integrated waste-to-resource management also offer great potential for lowering ethanol costs.

2. Early biomass-to-ethanol plants must rely on low-cost or disposal fee-based waste feedstocks. However, to meet the nation's sustainable alternate energy needs, DFSS must be developed. Early commercial developments must be cautious with baseline feedstock price structuring in order to facilitate the gap closure necessary to bring in DFSS; i.e., too high a tipping fee, or purchase of processed waste feedstocks below cost will directly compete with growers' ability to develop, produce, and supply low-cost DFSS within the agronomic/economic return range that can already be achieved with conventional feed or food crops.

WICO will continue to evaluate the feasibility of this project and technology, and will make continued efforts to position itself for success in the event that a decision is made to proceed with a project. WICO sincerely appreciates the funding and technical support provided by NREL. Completion of this feasibility study has put WICO in a much better position to evaluate objectively the potential business opportunities associated with biomass-to-ethanol technology, in the context of its other business opportunities.